Control Area Operations: The Debate over Consolidation

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Executive Summary

Although many participants in the restructuring debate in the power industry have argued for consolidation of control areas as the solution to a variety of problems, a review of recent evidence, including studies, actions taken by utilities, and FERC orders, shows that consolidation is not always the preferred solution. First, several utilities and generators have recently formed and/or switched control areas (sometimes by use of "pseudo-ties"), which implies the existence of a bilateral market in control area services. All of these changes have taken place within the constraints of NERC reliability criteria, and so have arguably not degraded reliability. Second, there are many substitutes for consolidation, including (a) better enforcement of rules prohibiting discrimination in the provision of control area services, (b) transmission rate design that supports bilateral markets in control area services, (c) the gradual reassignment of control area responsibilities over time as needs and economic consequences dictate, (d) reserve sharing agreements, and (e) area control error (ACE) diversity sharing agreements. Third, the existence of individual control areas may have helped limit the extent of recent blackouts and supported the restoration of service. Fourth, there is no "optimal" size of control area; control areas can be "too large" and "too small", both for reliability and economic purposes. In conclusion, regulatory policy should not interfere with the voluntary development of new control areas and related bilateral markets in control area services. Federal policy should not dictate consolidation, because it would interfere with voluntary exchange within the constraints imposed by reliability criteria, and with experiments in the design of new institutional structures.

Introduction and Purposes

The wholesale electricity industry has undergone significant change in the last ten years, especially through the establishment of new institutions such as Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs), the operation of newly designed markets for energy, capacity and ancillary services, continuing debates about the appropriate definition of transmission services, concerns about the lack of construction of new transmission capacity, resource portfolio standards, and investigations into the potential exercise of market power, among other issues. This paper focuses on only one dimension of the wholesale provision of electricity, which is however critical for both economic and reliable operations: the organization of control area or balancing authority activities. It explores options for relying on markets, contracts, and institutions to ensure that reliability criteria are met in the most economical fashion, and offers alternatives to federal "top-down" mandates.

Under the Energy Policy Act of 2005, the Federal Energy Regulatory Commission (FERC) was given more authority to oversee the development and enforcement of reliability standards. One outcome of the implementation of this authority is the re-examination of the various functions associated with operating what have traditionally been known as "control areas". Many of these functions are now defined to be the responsibility of "balancing authorities".[1] According to the North

[1] See "NERC Reliability Functional Model: Function Definitions and Responsible Entities", Version 3, February 13, 2007. Available at ftp://www.nerc.com/pub/sys/all_updl/oc/fmrtg/Function_Model_Version3_Board_Approved_13Feb07.pdf. The specific tasks associated with operating a Balancing Authority and the required relationships with other responsible entities under the Functional Model are detailed at pp. 23-25. According to the SPP Feasibility Study on consolidation of control areas (p. 6), "[a] control area, as defined by NERC is, 'An electrical system bounded by interconnection (tieline) metering and telemetry. It controls generation directly to maintain its interchange schedule with other control areas and contributes to frequency regulation of the interconnection.' NERC is phasing out the term 'control area.' In the new NERC Functional Model, functions traditionally performed by control areas are represented by various terms, such as 'balancing authority,' 'transmission operator' and others."

Amercan Electric Reliability Corporation (NERC) Functional Model (version 3), the Balancing Authority "maintains load-interchange-generation balance within a Balancing Authority Area and supports Interconnection frequency in real time."[2] In turn a Balancing Authority Area is defined as "[t]he collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area."[3] Although the definitions of these responsibilities are continuing to evolve, and the ultimate set of functions assigned to Balancing Authorities may well differ from those traditionally performed by Control Areas, in this paper "control area" and "balancing authority" will be used interchangeably. The purpose here is not to delve into the details separating these two approaches, but to review the options for ensuring that the specific tasks and responsibilities associated with control areas and balancing authorities are performed in a reliable and economical manner.

Control areas should not be confused with other types of organizations, entities, "responsible parties" (in NERC terminology), and institutions that have developed in the wholesale electricity industry. For example, RTOs and ISOs have been established in many parts of the country, including California, New England, New York, the upper Midwest (MISO), the lower Midwest (Southwest Power Pool, or SPP), and an area stretching from the mid-Atlantic states into the Midwest (PJM). These entities have responsibilities that range much more widely than just the operation of control areas or balancing authorities, and typically include the operation of centralized, auction-based

[2] Ibid., p. 23.
[3] Ibid., p. 5.

markets for various energy and capacity services, congestion management, and the definition and distribution of transmission rights.

Another type of entity is the "power pool", several examples of which have been in place for decades (and some of which evolved into ISOs or RTOs, such as PJM). Power pools typically have been responsible for the dispatch of generation from a collection of (usually thermal) resources, but have not operated markets or been involved in transmission access. Power pools were established as early as the 1920s to ensure least-cost dispatch from a group of generators owned by various vertically-integrated electric utilities, and involved agreements that required financial settlements after-the-fact to share the costs and benefits of centralized dispatch in real-time.[4]

For the purposes of this paper, a third type of entity is relevant: the Reliability Coordinator (also defined in the NERC Functional Model). The relationship between the Reliability Coordinator and the Balancing Authority is part of the institutional landscape:

> [t]he Reliability Coordinator is responsible for ensuring that the generation-demand balance is maintained within its Reliability Coordinator Area, which, in turn, ensures that the Interconnection frequency remains within acceptable limits. The Balancing Authority has the responsibility for generation-demand balance in the Balancing Authority Area. The Reliability Coordinator may direct a Balancing Authority within its Reliability Coordinator Area to take whatever action is necessary to ensure that this balance is maintained.[5]

In this paper, we take the role of the Reliability Coordinator as a given: the Balancing Authority is still the entity that must *take action* to ensure compliance with reliability standards. The Balancing Authority is still the entity with its "hand on the switch", so to speak.

[4] See, generally, Paul Joskow and Richard Schmalensee, "Markets for Power: An Analysis of Electric Utility Deregulation", MIT Press, 1983.
[5] NERC Reliability Functional Model, op. cit., p. 21.

The fundamental purposes for this paper are as follows: (a) to explore the tension between two approaches – consolidate versus maintain/expand the number of control areas; (b) to review current FERC policies on this issue and related issues (e.g., distinguishing among the various purposes for consolidation); and (c) to develop conclusions on appropriate policies in this area. Evidence is presented from a variety of sources, including (a) case studies of the formation of new control areas and decisions by utilities and independent generators to switch between existing control areas; (b) studies of the potential costs and benefits of control area consolidation; (c) examination of evolutionary approaches to reassigning control area responsibilities; and (d) regulatory decisions that have addressed these issues. In addition, evidence of the operation of control areas during emergency conditions is reviewed (both in the U.S. and Europe), to see if lessons can be learned from these "extreme events" about the most appropriate allocation of control area responsibilities.

Evaluation of the Potential Advantages of Consolidation

The debate about the "optimal" or "best" assignment of control area (balancing authority) functions has occurred in almost all areas of the U.S., especially in the context of the establishment of ISOs and RTOs. Advocates on both sides have used a variety of arguments and evidence in support of their positions. This section reviews some of these arguments.

Undue Discrimination

In the late 1990s, the Midwest ISO (MISO) was formed and approved by FERC.[6] In that context, several wholesale customers argued that they had suffered undue discrimination by control area operators (CAOs), and that control area functions should be transferred to MISO to ensure full non-discriminatory access to transmission capacity (which requires the use of control area services).[7] Similar arguments were made at the time by Wisconsin Intervenors[8], who stated that existing control area operators should not be guaranteed the ability to continue operating control areas. Two reasons were offered:

- Control areas had rights that other market participants did not have, and controlled reliability council decisions. Knowledge of all schedules and transactions, and real-time authority over participants, gave control area operators the ability to take actions to the advantage of some participants and the disadvantage of others.

- Control area operators acting as competitors in retail markets would be able to aggregate and balance all the loads in a control area, capture the diversity benefits of individual loads, and avoid imbalance penalties at ties with other control areas.[9]

In response to these arguments, FERC's order conditionally approving formation of the Midwest ISO imposed the following requirement: "[t]he commitment . . . to monitor, on an ongoing basis and in its 18-month assessment, the competitive and reliability

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[6] 84 FERC ¶61, 231, Docket Nos. ER98-1438-000 and EC98-24-000, September 16, 1998.
[7] Questions persist in MISO about the trade-offs between (a) potentially increased efficiencies associated with reducing the number of control areas and (b) the costs of MISO operations and the risks of the exercise of market power in MISO's centralized markets. See "COMMENTS OF THE INDUSTRIAL CUSTOMER GROUPS, WISCONSIN INDUSTRIAL ENERGY GROUP (WIEG), WISCONSIN MANUFACTURERS' & COMMERCE (WMC) AND WISCONSIN PAPER COUNCIL (WPC)", before the Public Service Commission of Wisconsin, Docket No. 05-ES-103, *Strategic Energy Assessment: January 1, 2006 Through December 31, 2012*, September 6, 2006, available at http://psc.wi.gov/apps/erf_share/view/viewdoc.aspx?docid=60559
[8] Wisconsin Public Power Inc., Wisconsin Industrial Energy Group, Madison Gas and Electric Company, Municipal Electric Utilities of Wisconsin, and the Wisconsin Federal of Cooperatives.
[9] See "WPPI's Supplemental Motion to Intervene Submitted by the Wisconsin Intervenors", May 19, 1998, ER98-1438-000, esp. pp. 24-29.

effects of allowing current control area operators to perform some control area functions."[10]

This argument and conditional approval occurred early in the days of Commission-ordered non-discriminatory open access, when the Commission was managing the initial implementation of Orders 888 and 889. In the case of MISO, the only or perhaps most obvious solution was to separate the operation of control areas from the question of access to transmission capacity. However, other means for removing undue discrimination are, and have been, available, including requirements for transparent operations.

Reliability

Wisconsin Intervenors also argued in the late '90s that MISO should act as *the* control area operator for reliability reasons: "[s]ystem reliability is a function of both transmission and generation control and coordination."[11] This argument focused on conditions in which "constraints or problems arise" that would threaten reliability. However, Wisconsin Intervenors tempered this argument by noting that it might be necessary *for reliability reasons* for MISO to operate *more than one control area,* in which case however MISO should operate *all* control areas. That is, Wisconsin Intervenors recognized that one large control area might *not* be the right answer in order to meet reliability standards. FERC's September 1998 order accepted the proposal to

[10] See 84 FERC ¶61, 231, September 16, 1998, Docket Nos. ER98-1438-000, EC98-24-000, p. 101. It is not clear that this condition was met, given subsequent changes in MISO's markets and corresponding FERC orders. A similar condition was imposed on the Southwest Power Pool (SPP) in the Commission's Order of October 31, 2006 in Docket Nos. ER06-451-009 and ER06-1467-000, p. 13, ¶32, in response to arguments from TDU Intervenors. SPP's report on consolidation of control areas is discussed in the following section.

[11] See COMMENTS OF THE INDUSTRIAL CUSTOMER GROUPS, op. cit., pp. 26-27.

form MISO conditional on further investigation of the potential effects of consolidating control areas, essentially leaving the issue of consolidation unaddressed.[12]

Functional Markets

In some cases, advocates of consolidation argue that larger control areas will enable markets to "function better", although that is rarely defined in a rigorous fashion, which makes the hypothesis hard to test. Presumably "market functioning" could be judged by the resulting efficiency of dispatch (on the generation side) as well as opportunities for maximizing the use of transmission capacity, subject to reliability constraints. "Functional markets" could also be defined in terms of broader measures of economic efficiency, including indices of competitiveness or cost minimization. In one case (GridFlorida), the potential for improvements in energy markets was investigated, assuming the elimination of pancaked transmission rates due to the consolidation of control areas.[13] The study found, however, that there was little potential for improved efficiency in energy markets, because the existence of multiple control areas did not impede trading in energy that ultimately reduced the cost of generation.

Support for Renewable Resources

Advocates for renewable resources have argued for larger control areas, thus consolidation, because of the expectation that a larger pool of dispatchable generation within the control area will increase the amount of generation that can help integrate

[12] The Electric Power Supply Association (EPSA) also supports consolidation of control areas to improve reliability; see www.epsa.org/forms/documents/ArticleFormPublic/viewArticle?id=372200000016.
[13] Again, this appears to falsely assume a necessary complementarity, in this case between consolidation of control areas and transmission rate design. As will be seen below, transmission rate design may be a substitute for consolidation of control areas, because it may enable broader trading of control area services. Fundamental economic concepts may have been misused in the case of GridFlorida.

renewable resources such as wind generation. Theoretically, the larger the control area, the more options for generation to be put "on regulation": automatic generation control (AGC). Such options could include both the choice among generation units as well as the total amount of generation "on regulation". Units on regulation can respond instantaneously to frequency excursions caused both by loads and by intermittent resources within the control area. However, regulating reserve service can be delivered via telemetry and the use of dynamic schedules or pseudo-ties, at least in some circumstances (i.e., within geographical limits). If so, then adjacent or nearby control areas could actually provide regulating reserves to intermittent resources physically interconnected in a different control area; FERC has recently approved such arrangements in California (see the discussion below of pseudo-ties).

Operational Transfer Capability

During the debate in the Northwest in the late 1990s and early 21st century about transmission restructuring, PacifiCorp modeled the potential cost savings associated with the combination of control area consolidation and a shift from contract-path to flow-based scheduling. This study *assumed* that Operational Transfer Capability (OTC) would increase by five-to-ten percent of Total Transfer Capability (TTC) due to consolidation and flow-based scheduling, and that generation dispatch costs would fall as a result by amounts in the tens of millions of dollars per year. However, there was no logical connection made between (a) the combination of consolidation and flow-based scheduling and (b) the increase in OTC, nor was there any consideration of options for increasing OTC that would avoid consolidation of control areas. Therefore, this study is not conclusive.[14]

Reduction in Regulating Reserves

Another possible benefit of consolidation is that merging control areas could lead to a reduction in the total amount of generation that must be held aside as regulating reserves. This reduction would be possible if there is diversity in the load patterns in the different control areas, such that increases and decreases in loads would offset each other in the merged control area, thus reducing the total amount of regulating reserves needed after consolidation to maintain frequency. This possibility was investigated in the SPP Feasibility Study,[15] which also noted that a reserve-sharing arrangement could lead to the *same or similar* outcome (p. 11 and Appendix 9.5): individual ACEs could be telemetered to SPP, which would aggregate the errors and send back signals for the adjustment of generation to the individual control areas whose errors had the same sign as the aggregate error. This way those control areas contributing to the aggregate error would be required to adjust generation to reduce the total, whereas those control areas mitigating the aggregate error would not be required to adjust generation. The total amount of generation on regulation could be reduced in recognition of ACE diversity, without causing costs to increase for those control areas that were not causing the aggregated ACE to increase (in absolute value).[16]

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[14] See www.bpa.gov/corporate/business/restructuring/archives/gridwestcomment/Appendix%204.pdf.
[15] See "Control Area Consolidation Feasibility Study", prepared by The Operational Control Task Force of the Southwest Power Pool, January 6, 2005.
[16] See also Blumsack, Seth, "Measuring the Benefits and Costs of Regional Electric Grid Integration", *Energy Law Journal*, vol. 28, 2007, pp. 147-184.

Quantitative Studies

Over the past ten years, several studies have been conducted of the costs and benefits of potential changes in control area operations, as a part of broader packages of proposed institutional reforms. These include studies by or for GridFlorida, Grid West, and the Southwest Power Pool.

The study for GridFlorida compared three cases: (a) a Base Case reflecting then-current market operations, individual control areas, separate transmission providers, and pancaked transmission rates; (b) a Day-1 Case (for a duration of three years), which eliminated only pancaked transmission charges; and (c) a Day-2 Case (for ten years after the transition from the Day-1 Case), which assumed centralized unit commitment and dispatch, as well as a single transmission tariff. The Day-2 Case included one main control area (run by an RTO) and several Control Zones operated by the existing utility control areas.[17] The individual Control Zones would work with the GridFlorida Control Area to meet overall reliability requirements in a hierarchical structure similar to that evolving in MISO. In general, the study found that formation of an RTO in Florida would not be cost-effective for consumers, for a variety of fact-specific reasons related to the operation of a robust bilateral wholesale market in Florida, high interconnectivity between control areas, *plus* a pre-existing reserve sharing agreement. The latter is critical for the purposes of this paper: the Florida Reliability Coordinating Council (FRCC), one of the regional reliability councils operating under the NERC umbrella, had established an understanding of how the operating reserves associated with the single largest contingency within the FRCC would be allocated among FRCC member control areas. Thus, one of the potential advantages of control area consolidation had already been

[17] Op. cit., p. 34.

achieved, *without consolidation*. In part for this reason, the potential incremental benefits of consolidation were outweighed by the incremental costs.

Similarly, GridWest examined the potential benefits of shifting to centralized markets for control area services as part of the formation of an RTO.[18] Because of questions about the extent of participation in GridWest, the study examined two scenarios with different numbers of control areas consolidating. Although the estimated benefits of centralized real-time dispatch (which is actually more of a "power pool" function than a "control area" function) were relatively large, the estimated savings from consolidating control areas and creating markets for contingency and regulating reserves were relatively small (about one-sixth of the estimated benefits of centralized redispatch). Thus, it is possible to distinguish, at least in this study, between changes in the cost of production related to operation of a power pool vs. operation of a single control area, and to conclude that the former significantly outweighed the latter.[19]

In response to a FERC order of February 2004, the Southwest Power Pool undertook a specific study of the feasibility of consolidating control areas.[20] The benefit of this study is that it focused solely on the question of consolidation, and assumed that all other aspects of wholesale markets, whether for energy or transmission, remained unchanged. Savings were expected from reductions in regulation reserves, offset by additional costs incurred by SPP in order to provide consolidated control area functions.

[18] Op. cit., note 14.

[19] It should be noted that the study characterized both types of benefits as being driven by control area consolidation and operation of a single AGC system. However, centralized dispatch is possible across multiple control areas, if "dispatch" is understood as "before the hour of delivery". The GridWest study did not study the possibility of centralized dispatch without consolidation of control areas. This points to the need for careful description of any proposed changes, separating decisions made at different points in time prior to and during the hour of delivery.

[20] Op. cit., note 15.

In addition, some control areas foresaw the possibility of savings by avoiding future certification requirements related to system operations and balancing authority functions.

As part of the study, SPP conducted a survey of its members regarding the potential need for consolidation of control areas. The response is revealing (p. 7):

> Over a third of control areas that responded to the OCTF survey indicated that they had provided regulation services to entities outside their control area. Furthermore, the SPP tariff allows customers to source transactions from anywhere within the SPP footprint for a fixed, zonal rate. Therefore it does not appear that control areas provide a barrier to the procurement of ancillary services.

Actual experience in the SPP thus demonstrates that decentralized markets in control area services can operate without consolidation of control areas. Although this evidence does not prove anything about the liquidity or the efficiency of such markets, it does demonstrate that bilateral trades among willing buyers and sellers take place. The key appears to be the nature of transmission services offered: control area services are by definition normally classified as "capacity" products, sometimes with associated energy. Accordingly, transmission capacity must be reserved for a service that typically has a very low capacity factor. For example, 100 MW of transmission capacity may be reserved for a dynamic schedule that must integrate on any hour to an amount of energy less than 100 MW to avoid penalties; depending on the expected amount of within-hour fluctuations in loads, the transmission customer might schedule and take delivery of an integrated amount of only 50 aMW on a typical hour. As a result, in some situations the cost of transmission can make remote sources of regulating and operating reserves uneconomic. However, the SPP transmission tariff has taken care of this problem, by establishing a zonal rate that supported transactions in control area services.

Another interesting result of the study concerns the relationship between reliability and consolidation. Here the SPP was also clear (p. 8):

> Furthermore, as a result of studies done after the 2003 blackout, SPP has followed industry recommendations and enhanced key areas of its operations and attained better visibility of the RTO's transmission system in its entirety among several other improvements. The consolidation of control areas does not inherently give SPP any additional reliability data beyond what it collects today. It is therefore believed that the number of control areas does not affect SPP's ability to maintain reliability.

Again, this demonstrates that consolidation is *not* a necessary (or even sufficient) condition for reliable operations.[21]

One important result of the SPP effort was a simple description of an Area Control Error (ACE) sharing arrangement, or a "supplemental regulation service shared by multiple parties".[22]

> The method requires that each Existing [Control] Area would continue to calculate its ACE as it does now with existing metering and software and then send that value to SPP. SPP would then calculate the resulting total or net SPP ACE. The SPP ACE value would be allocated back as a proportional share of the Existing ACE only to those Existing [Control] Areas that were contributing unfavorably to the SPP ACE, i.e.[,] those areas with an ACE value with the same sign as the SPP ACE. The remaining areas would be allocated zero or a small portion of their ACE to prevent it from reaching extreme values in either direction. The allocated value would then be sent back and applied to the Existing [Control] Area's Automatic Generation Control system instead of the ACE value. In all cases, the resulting allocation would be less than or equal to their ACE value sent to SPP.

This again offers an alternative to consolidation of control areas: sharing of Area Control Errors among several control areas (or balancing authorities), thus reducing aggregate ACE across the control areas, combined with a reasonable method of assigning to

[21] This topic will be addressed further below in the section on the U.S. and European blackouts.
[22] See Appendix 9.6, p. 24, quoting from the SPP's "2001 Control Area Implementation Task Force Final Report".

individual control areas the responsibility for bringing the *collective* ACE down by creating appropriate incentives to minimize ACE.

These studies clearly yield interesting conclusions about the potential net benefits of consolidating control areas. When pre-existing conditions (e.g., in Florida) and the option for ACE sharing (e.g., in the Southwest Power Pool) are taken in account, one conclusion is that the potential for quantitative benefits from consolidation of control areas may be *both* limited *and* achievable by other means. In addition, the separation of the benefits of control area consolidation from those of centralized dispatch similar to a power pool (e.g., in the GridWest area) suggests that control areas can continue to operate independently in conjunction with systems that minimize the cost of dispatch ahead of the hour of delivery. The picture painted by these studies is much more complicated that might be suggested by a simple argument in favor of or against consolidation of control areas.

Recent Changes in Control Area Operations

The variety of institutional structures across the country, combined with continuing investigations into the feasibility and economic/reliability effects of consolidation, has yielded a complicated picture of changes in control area functions over time. These changes have been driven by different factual considerations in each case, which suggests that it is difficult to determine a "one size fits all" answer to the question of consolidation.

FERC Approvals of Pseudo-Ties

According to FERC, "[a] pseudo tie is a telemetered reading or value that is updated in real time and used as a tie-line flow in an area control error equation and allows a generator in one control area to *appear to be* in another control area electrically. The integrated value is used as a metered megawatt hour (MWH) value for interchange accounting purposes."[23] In effect, pseudo-ties are used to "electrically move" loads or resources between control areas. For example, if a resource is electrically located in Control Area A but "connected" via a pseudo-tie to Control Area B, movements in the resource's output are integrated into B's AGC/ACE equations (not A's), and B (not A) must respond to changes in the resource's performance and comply with reliability criteria. Similarly, if a *load* is electrically located in A's Control Area but connected via pseudo-tie to B's control area, then B (not A) must provide AGC for that load.[24] An important implication is both cases is that A is no longer the responsible Balancing Authority for either the load or the resource; rather, B has assumed that responsibility. The existence of pseudo-ties, and their regulatory status, is further demonstration that bilateral markets in control area services are at least feasible.

The FERC has recently approved pseudo-ties, thus sanctioning the movement of resources from one control area to another, despite arguments that pseudo-ties would "balkanize" control area operations and reduce reliability.[25] In the case of the transfer of transmission facilities from the California ISO (CAISO) to the Sacramento Municipal

[23] See "ORDER ACCEPTING AMENDMENTS TO OPERATING AGREEMENT AND OPERATING AGREEMENT", Docket Nos. ER05-1522-000 and ER05-1533-000, November 30, 2005, p. 2, note 6 (emphasis added).
[24] See, for example, the definition of pseudo-tie in www.illinois-auction.com/resources/applications/Ameren_Ancillary_Services_Self_Supply_Requirement.doc, applicable to loads seeking to self-supply ancillary services from a Balancing Authority other than Ameren.
[25] Op cit., note 15.

Utility District (SMUD), the Commission noted that both entities involved, CAISO and SMUD, are WECC-certified control areas (¶13), and are thus responsible for compliance with reliability standards, notwithstanding which loads or generators might physically be located in various control areas.

In November 2005, the CAISO described an arrangement by which Calpine's Sutter generating facility would be connected via pseudo-tie to the CAISO, despite the fact that the facility is physically connected to the Western Area Power Administration (WAPA) and thus electrically located within SMUD's control area. Along with the pseudo-tie arrangement, Sutter reserved the right to "lay-off" energy to the SMUD control area by submitting a static export schedule through the CAISO market.[26] Thus, commercial transactions can be scheduled through the CAISO either dynamically via the pseudo-tie or statically through an ISO market. This arrangement was sanctioned by the Commission in December 2005.[27] In addition, a similar (but reverse) arrangement was proposed by the CAISO in 2006, moving WAPA's New Melones hydro resource from the CAISO control area to the SMUD control area.[28] Pseudo-ties are also used in the Joint Operating Agreement between MISO and the Mid Continent Area Power Pool (MAPP), and are being implemented in the Southwest Power Pool.[29]

[26] See CAISO, "White Paper, CAISO Control Area Footprint, Effective December 1, 2005", November 21, 2005.
[27] 113 FERC ¶ 61,261, "ORDER ON PSEUDO PARTICIPATING GENERATOR AGREEMENT", Docket No. ER06-58-000, December 15, 2005.
[28] See CAISO, "Draft White Paper, CAISO Control Area Footprint, C4 Network Model Implementation", effective September 28, 2006.
[29] See MISO/MAPP compliance filing, May 16, 2005, Docket Nos. ER04-691-023, EL04-104-022, ER04-960-002, et al. See also http://www.spp.org/publications/PRR137%20Training%20-%20External%20Generator%20Participation.pdf.

Turlock Irrigation District, 2002-05

In 2002, the District decided to form its own control area. There were four main drivers for this decision. First, under the policies of the California ISO, rolling blackouts had been imposed on Turlock during the energy crisis of 2000-2001, despite the fact that Turlock had contracted for enough power that it was either "long" or in load-resource balance. Prudency was, in this case, not rewarded. (This was also a motivating factor in SMUD's decision to form its own control area, which is discussed below.) Turlock wanted to avoid the possibility that these rolling blackouts would continue notwithstanding the District's future decisions about resource acquisitions. Second, economic analysis suggested that Turlock's retail customers would benefit from the ability to reduce direct payments to the California ISO (Grid Management and Scheduling Coordinator fees), which suggests that the CAISO had exceeded available economies of scale. Third, Turlock expected to gain greater control over its costs and operations over time, because of the ability to avoid the uncertainty associated with the ISO's tariff, including the potential for future litigation over refunds. Reduced uncertainty itself had an economic value. Finally, as a control area, Turlock could potentially become a supplier of control area services by selling directly into the ISO ancillary service markets without having to join the ISO formally or sign an agreement as a "Participating Generation Owner".[30] Any margins earned on such sales would reduce retail rates. These benefits were expected to offset the incremental costs that Turlock would incur in order to establish the control area, including staffing, hardware, software, and training, and to maintain its own spinning reserves. Development of the new control

[30] See FERC Docket No. EL99-93-001 for details on Turlock's attempt to sell ancillary services into the ISO markets before it became a separate control area. See also FERC Docket Nos. ER05-405 and ER04-693, which address related issues.

area took several years, in part because of changes required at Turlock, and in part because of the need to negotiate arrangements with the ISO, which was also facing the formation of SMUD's separate control area and the shift by WAPA and the Modesto Irrigation District into SMUD's control area. Turlock's new control area "went live" in December 2005.

Western Area Power Administration, 1998

A few years before the West Coast energy crisis, the Desert Southwest and Rocky Mountain Regions of the Western Area Power Administration took over responsibilities previously performed by the Upper Colorado Control Area (1998). There were two motivating factors for this decision: economic benefits in the form of cost savings, and reductions in transactions costs associated with entities and organizations outside WAPA who were considering changes in the operation of the regional transmission grid.[31]

> On April 1, 1998, Western began operations in what used to be called the Upper Colorado Control Area. As part of our plan to streamline operations and cut costs we are consolidating this control area into two adjacent control areas managed by Western's Desert Southwest and Rocky Mountain regions. The change, which includes both transmission switching and control area operations, yields significant benefits to Western and to our customers. We'll be able to provide enhanced coordination with emerging regional transmission groups. Our dispatchers will gain increased operational flexibility and Western will realize capitalized cost savings by eliminating the Supervisory Control and Data Acquisition system replacement planned for Montrose.

In this case, consolidation within a single institution made sense for several reasons, driven mainly by economic factors. It was not driven by "top down" mandates that may have ignored economic consequences.

[31] See http://www.wapa.gov/crsp/opsmaintcrsp/consolidation.htm.

Southwest Power Pool, 2005-06

In a response to a FERC order, the Southwest Power Pool conducted a lengthy control area consolidation feasibility study in 2005, which reached the following conclusions.[32]

> The consolidation of control areas does not inherently give SPP any additional reliability data beyond what it collects today. It is therefore believed that the number of control areas does not affect SPP's ability to maintain reliability. (p. 8)
>
> Over a third of control areas that responded to the OCTF survey indicated that they had provided regulation services to entities outside their control area. Furthermore, the SPP tariff allows customers to source transactions from anywhere within the SPP footprint for a fixed, zonal rate. Therefore it does not appear that control areas provide a barrier to the procurement of ancillary services. (p. 7)

In other words, the lack of consolidation did not degrade reliability or the flow of information, and consolidation was not a necessary condition for the establishment of markets. Further,

> SPP's market centers around a security-constrained economic dispatch that optimizes resources across the market footprint without respect to control area boundaries. Thus many of the efficiencies that would be realized within a single control area will already be realized by SPP's imbalance market. The task force, therefore, does not believe multiple control areas impede wholesale energy markets. (p. 8)

Thus, market-based solutions in the face of multiple control areas were both feasible and deemed efficient. These conclusions suggest that there were, as of early 2005, no obvious reliability or economic benefits to be achieved by consolidation of control area functions within the SPP.

FERC's 2006 Order[33] required SPP to "re-assess the feasibility, cost, and benefits of any control area consolidation following its first year of imbalance market operation

[32] See http://www.spp.org/publications/Feasibility%20Study%201.0.pdf, http://www.spp.org/section.asp?group=368&pageID=27, http://www.spp.org/publications/ORWGminutes6Jan05.pdf, and http://www.spp.org/publications/BODMktStatus112006.pdf for background.

and to file its re-assessment with the Commission within 15 months following the start of market operations." Imbalance markets began operation on February 1, 2007, and in the spring of 2008 SPP submitted further reports to FERC. In particular, SPP reported an agreement to move ahead with a modest amount of expenditures on consolidation, but with limited evidence of benefits:

> BAs Agree: Estimated benefits are somewhat subjective, but appear to exist in terms of reduced burden on regulation due to inaccuracies in the market dispatch. Worst case the relatively marginal system implementation cost of less than $2M represents a full cost to the members for implementation with no immediate and measurable offsetting benefit. Balancing Authorities agree that BA consolidation in advance of the implementation of future market phases would facilitate that implementation. However the BAs also believe that this intermediate step should be taken in conjunction with a commitment for some future market implementation of at least Ancillary Services, Day Ahead Unit Commitment and Day Ahead Energy Markets. BAs agree that the work to further document and develop the details[,] protocols and project implementation should begin in earnest, so that the implementation of the project plan can begin immediately upon confirmation that further market steps will occur.[34]

On May 13, 2008, SPP submitted a cost-benefit analysis to FERC, which concluded, based on four days of data, that the benefits of consolidation would outweigh the costs.

> Previous study efforts identified similar benefits but struggled to quantify a value on any of these. Likewise, this analysis describes many of these benefits in qualitative fashion. However, the EIS market implementation has made operating data available that SPP used to perform analysis over 4 sample days of the reduction of regulation burden. Based on that analysis, SPP quantifies the value of this benefit ranging from approximately $3.8MM to $19.3MM of reduced energy savings per year. Although this analysis further identified a potential for reduction in capacity required for regulation, it is unknown how or if that will actually be realized without a unit commitment market.

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[33] "Order on Tariff Filing and Compliance Filing", Docket Nos. ER06-451-009 and ER06-1467-000, October 31, 2006, p. 15, condition (F).

[34] See SPP filing of May 1, 2008 in FERC docket no. ER06-451-000. The excerpt is from Southwest Power Pool, "Balancing Authority Consolidation Implementation Plan", version 2.1, revision of Dec. 12, 2007, p. 6, attached to the May 1 filing.

It remains to be seen if these estimates hold up to further analysis. It is possible that SPP's method of extrapolation from four days to a full year will prove reasonably accurate, but at this point that is uncertain.

GridWest, RTO West, and Transmission Improvements Group

In the Pacific Northwest, discussions of options for transmission restructuring have been underway for well over ten years. One of the major issues throughout these discussions has been the potential for benefits if control areas were consolidated. The most recent studies of such potential benefits were conducted by GridWest and the Transmission Improvements Group (now both dissolved and replaced, in effect, by ColumbiaGrid and the Northern Tier Transmission Group).[35]

In an early 2006 study, a technical review group formed by GridWest provided estimates of potential savings from the then-current GridWest proposal, which included consolidation of control areas.[36] One helpful aspect of this study is that two different options for consolidation were studied, which at least theoretically could lead to conclusions about the *incremental* effects of a specific type of consolidation. However, the GridWest proposal, like many of its ilk, included not only consolidation of control areas but also the establishment of centralized markets for control area services. Thus, the estimated benefits are driven by *two* significant changes, and it is not possible with

[35] See www.columbiagrid.org and http://www.nttg.biz/site/.
[36] "A Summary of the Estimated Benefits of Grid West", January 9, 2006, available at www.bpa.gov/corporate/business/restructuring/archives/gridwest/2006docs/GW_Forum_Meeting/Benefits%20Estimate%20(Jan%209,%202006).pdf

the available information to sort out or decompose the estimates into those associated with consolidation versus new markets.[37]

One critical assumption of the analysis by GridWest was that sufficient transmission rights would be available to enable transactions in new markets for real-time energy balancing and reserves. There was no attempt to examine or quantify available transmission capacity (ATC) for these new transactions, and thus the feasibility of the proposed new markets is unclear.[38] However, assuming that ATC would be available, the study estimated benefits of $147 million to $335 million per year associated with a real-time energy balancing market, $27 million to $37 million per year associated with contingency reserves, and $16 million to $21 million associated with regulating reserves.[39] In each case, the lower end of the range is associated with consolidation of eight control areas, while the upper end of the range is associated with consolidation of ten control areas. The costs of achieving these potential benefits were not estimated. All of these benefits were assumed to derive from consolidation of control areas *in combination with* the establishment of markets in various ancillary services (energy imbalance, contingency reserves, and regulating reserves). Without better information, we cannot segregate the sources of any of these potential gross benefits, let alone the net benefits after accounting for costs of consolidation.

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[37] In the case of contingency reserves, the study used BPA's posted average-cost charge to value the potential reduction in reserve requirements. This probably understated the potential benefit of such reductions, because the freed-up capacity would presumably be used to generate energy that would displace more expensive sources.

[38] As of 2007, BPA has taken efforts to "clear the queue": several thousand megawatts of transmission service requests, some of which have been in BPA's queue for several years, would be subject to an "open season" process in an attempt to eliminate waiting for studies (impact and facilities) to be completed. This implies that ATC is *not* sufficient to support new transactions, unless GridWest had been successful in implementing a new flow-based approach to modeling transmission use, which might have freed up transmission capacity for these new markets. See www.transmission.bpa.gov/business/IssuesPolicySteeringCmttee/default.cfm?page=itpt.

[39] Table 1 in the study is not labeled, so these magnitudes are inferred. Also, the study notes the potential for overlapping estimates, so these numbers should not be added together.

Another study, funded by the Transmission Improvements Group and prepared by Global Energy, found several potential sources of benefits associated with consolidation, including improved reliability and security, reductions in contingency and regulating reserves, and improved real-time re-dispatch.[40] These are not directly analogous to the categories of benefits estimated for GridWest, although there was substantial overlap in the geographical and electrical "footprint" of the two studies. Global Energy's estimates of potential benefits associated with improved reliability, increased OTC (thus more efficient dispatch of generation), within-hour re-dispatch, and reduction in contingency and regulating reserve requirements (Table 3-2) are in the range of $24 million to $108 million per year, depending on various assumptions, including how many control areas might consolidate. Again, this approach at least has the value of distinguishing *incremental* savings from consolidating different control areas. Specifically, in the area of contingency reserves, three different combinations of consolidation were examined, with benefits ranging from $11 million to $40 million on the low side, to $21 million to $81 million on the high side.[41] Although it might be tempting to identify the difference between the GridWest and TIG estimated benefits as driven by the existence (or not) of centralized markets, this would not be correct, because the studies differed in other respects. However, the study commissioned by TIG did explicitly take into account constraints on transmission capacity, which the GridWest study did not.

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[40] See www.tig-nw.kristiwallis.com/wp-content/GlobalEnergyBenefitsStudyTIGProposalsFINAL.pdf
[41] The difference between "low" and "high" was based on the assumption regarding how much bilateral contracting is already occurring in the absence of centralized markets for contingency reserves. Note the similarity with the SPP Feasibility Study, which found substantial bilateral contracting without consolidation, aided by a specific transmission rate design.

Midwest Independent System Operator (1998 – present)

The tension between consolidation and disaggregation has also been evident in the continuing development of the Midwest Independent System Operator (MISO). Actual shifts in control area (balancing authority) functions have been underway since MISO was created in the late 1990s. One of the proponents of transferring and consolidating responsibilities was (and is) Wisconsin Public Power Inc. (WPPI), a joint action agency of almost 50 municipal utilities in Wisconsin, upper Michigan, and Iowa. WPPI members are located in several control areas, which complicates contracting and operation of the combination of WPPI resources and wholesale purchases from other suppliers. Before the creation MISO, WPPI was concerned about the ability of control area operators to discriminate in the supply of control area services, making it more difficult or expensive for third parties to integrate their own power supplies compared with power purchased from the control area operator's merchant function.[42]

According to FERC's September 1998 Order,[43]

> Wisconsin Intervenors assert that Transmission Owners should not be allowed to continue operating control areas because this will give them a "significant competitive advantage" relative to those participants that do not operate control areas. They highlight four particular problems: (1) control area operators will have knowledge of all schedules and transactions involving participants in their control areas; (2) control area operators' real time authority over other participants will allow them to take actions "purportedly" for system reliability that could put other participants at a competitive disadvantage; (3) control area operators will not pay load penalties because they will have access to inadvertent energy accounts that allow them to pay back positive and negative imbalances in kind while non-control area participants would to pay these penalties; and (4) control area operators will be able to obtain the economic benefits of the imbalance diversity of individual customers within that geographic area.

[42] WPPI joined with other parties in raising these concerns in FERC Docket Nos. ER98-1438-000 and EC98-24-000.

[43] "Order Conditionally Authorizing Establishment of Midwest Independent Transmission System Operator and Establishing Hearing Procedures", September 16, 1998 (84 FERC 62,231, pp. 76-78, footnotes omitted).

> To avoid these problems, Wisconsin Intervenors urge the Commission to require explicitly that the ISO will be the control area operator for all members as soon as practicable. They also request the Commission to clarify that the power and authority to operate a control area rests at all times with the Midwest ISO and may be delegated back to owners to achieve the phase-in.

In the Order authorizing the formation of MISO, FERC allowed existing control areas to be maintained, but accepted the proposal that MISO should "have responsibility over many control area functions" (pp. 79-80). Thus, FERC approved a *division* of control area responsibilities between pre-existing control area operators and the newly formed MISO. However, the approval was conditional: first, MISO had to file a detailed summary of operating and emergency procedures (p. 98), and second MISO had to monitor competitive and reliability effects of allowing control area operators to continue to perform certain functions (p. 101).[44] In addition, FERC encouraged MISO to investigate other options for assigning and managing control area functions, including "master-satellite" arrangements, development of a regional balancing market, and communication of scheduled net (not disaggregated) interchanges between control areas by MISO to control areas (p. 103). Further, the Commission attempted to distinguish "generation control" from "transmission control", recognizing that the distinction is not always clear. MISO was given "functional control over transmission" but only some "generation control". This appears to recognize the "natural monopoly" or "essential facility" nature of transmission services.

During the evolution of MISO's approach to control area responsibilities over the last ten years, various approaches have been considered with respect to the consolidation of control area responsibilities. In the fall of 1999, the MISO Policy Sub-Committee was

[44] Based on documents available on the MISO web site, these conditions were subsumed in later filings of MISO, as the Commission's approach to ISOs and RTOs have continued to evolve (e.g., under Order 2000).

formed to develop a recommendation for congestion management for the ISO. At the time, there were two main competing views regarding the best approach to congestion management: flow-based physical transmission rights, and locational marginal pricing (LMP). The Sub-Committee ultimately developed a hybrid approach, combining flow-based physical rights up through pre-schedule, with LMP taking over in real time (sometime after pre-schedule deadlines). Although one purpose of this proposal was to demonstrate how a broad LMP system could work with multiple control areas, the discussion examined various approaches to "regional coordination" of pricing without consolidation of control area functions.

> In the absence of consolidating the dispatch functions at the RTO level, there is a need for an LMP-based procedure that can permit efficient RTO-wide congestion management, while not requiring all control areas within the RTO's region to consolidate into a single control area. If an emerging RTO is starting from the basis of multiple control areas, and there are no immediate plans to move towards a substantial degree of control area consolidation, then the goal of a regional market must be pursued through some method of intercontrol area coordination.[45]

Although the context of this discussion is the division of responsibilities between a newly formed ISO, such as MISO, and pre-existing control areas, the conclusions can be generalized to situations in which there is no ISO or RTO, and thus no centralized markets. The major conclusion is that it is possible to design systems in which control area responsibilities are *divided* between and among different entities. This approach allows individual control areas to decide which functions are most cost-effective to perform separately, and which are more cost-effectively performed by another entity, be that an RTO, an ISO, *or a different control area*. There are several critical criteria in these decisions, including both the relative advantages and disadvantages of separate

[45] *Ibid.*, pp. 17-18.

control areas from the perspective of consumers inside and outside the control areas at issue.

The tension between consolidation and preservation of pre-existing control areas continued in MISO's filing in compliance with Order 2000.[46] In response, the Illinois Commerce Commission (ICC) filed comments noting that the compliance filing did nothing to phase out pre-existing control area operator functions.[47] According to the ICC, FERC's Order 2000 contained somewhat confusing, and possibly contradictory, guidance on this issue: FERC did not require RTOs to operate a single control area in the traditional sense, but *did* require RTOs to have "operational authority" for transmission facilities under its control. The ICC asked FERC to require the MISO to consider a hierarchical control structure that would give the ISO some measure of authority over existing control area operators, and eventually the phased-in consolidation of control area functions over time. Ultimately, FERC accepted the MISO compliance filing, as supplemented, and thus agreed with the division of control area responsibilities between existing control area operators and the ISO.[48] This decision, upheld on rehearing, focused on the authority of the MISO to (a) order redispatch for reliability reasons, (b) approve and disapprove requests for scheduled outages of transmission facilities, (c) honor and monitor compliance with reliability standards, and (d) issue scheduling instructions and emergency actions based on reliability concerns. Specifically, FERC concluded that "[t]hrough this hierarchical structure the Midwest ISO has clear authority over redispatch for reliability purposes of generation connected to transmission facilities it operates and,

[46] FERC Docket No. RT01-87-000, January 16, 2001.
[47] Comments of the Illinois Commerce Commission, Docket No. RT01-87-000, March 8, 2001.
[48] 97 FERC ¶61,326, December 20, 2001, Docket Nos. RT01-87-000 et al., "Order Granting RTO Status and Accepting Supplemental Filings".

therefore, meets the requirements of this RTO characteristic."[49] It is noteworthy that this decision by the Commission focused solely on *reliability* concerns, and not about *economic* outcomes.

In mid-2003, MISO moved to the next stage in its evolution: a proposed Transmission and Energy Markets Tariff (TEMT), which included market-based congestion management and energy spot markets (day-ahead and real-time) governed by LMPs and financial transmission rights (FTRs).[50] The first TEMT proposal again reallocated control area responsibilities between MISO and existing control area operators.[51] Although the first proposal for a TEMT was eventually withdrawn and replaced, FERC provided some significant guidance on control area responsibilities in its order accepting the withdrawal:

> 46. Given the large number of control areas in the Midwest ISO footprint, the variation in how those control areas are operated, and the fact that the traditional control area concept does not always map consistently into the functions required in the restructured electricity markets, the Midwest ISO should adopt the recent NERC classification of NERC service functions as a method of organizing future discussions of the allocation of responsibilities for reliable market and power system operations. Those categories are: Reliability Authority, Balancing Authority, Interchange Authority, Transmission Service Provider, Transmission Owner, Transmission Operator, Market Operator, and Planning Authority. The Midwest ISO should state clearly the current responsibilities under each of these categories and the proposed changes in those responsibilities. That is, under this approach, each current entity with functional and operational responsibility would be mapped into existing or revised functions under these service headings. For example, a significant change proposed in the July 25th Tariff filing is the shift in certain Balancing Authority responsibilities from the control area operators to the Midwest ISO.[52]

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[49] *Ibid.*, p. 20.
[50] Docket No. ER04-691-000.
[51] There is no simple way to describe the differences between responsibilities assigned to MISO and to control area operators. For a summary, see ¶¶25-30 of FERC's "Order Granting Motion to Withdraw Filing and Providing Guidance", October 29, 2003, Docket No. ER03-1118-000, 105 FERC ¶61,145.
[52] *Ibid.*, pp. 13-14, footnotes omitted. FERC's concern about clear delineation of control area responsibilities was heightened by the August 2003 blackout in the Eastern Interconnection.

This is a significant development, because it demonstrates that the Commission had become interested in using the NERC functional model to judge proposals for the allocation of control area (now Balancing Authority) responsibilities.

After the TEMT was refiled (March 2004), FERC accepted the new tariff (August 2004[53]) and adopted a new approach to control area responsibilities tied directly to the NERC Functional Model:

> 97. In the TEMT Order, the Commission advised that the Midwest ISO and stakeholders adopt the NERC Reliability Functional Model (Functional Model) as a basis for discussions on the allocations of responsibilities for reliable market and power system operations. The Commission also required that the revised TEMT "state clearly the current responsibilities under each of these categories and the proposed changes in those responsibilities." We note here that the NERC Functional Model does not prescribe any particular organization or market structure. That is, the functions are intended to be consistent with alternative market designs. Hence, we recognize that there is more than one way to implement the Functional Model to accommodate particular market designs. (p. 33, footnotes omitted)

Under the TEMT proposal, (1) MISO would be the Reliability Authority, (2) MISO and control area operators would share the Balancing Authorities function, (3) MISO would act as Transmission Service Provider, and (4) MISO would act as Interchange Scheduling Agent (similar to Interchange Authority).[54] Transmission owners would be Transmission Operators, and generation owners would be Generation Operators, using the NERC definitions. The revised TEMT proposed that control area operators retain responsibility for ensuring adequate regulation and operating reserves.[55] FERC accepted these assignments *notwithstanding* the fact that MISO was *not* proposing markets for regulation and operating reserves. However, FERC also reiterated its support for

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[53] 108 FERC ¶61,163, "Order Conditionally Accepting Tariff Sheets to Start Energy Markets and Establishing Settlement Judge Procedures", August 6, 2004, Docket Nos. ER04-691-000 and LE-04-104-000.
[54] *Ibid.*, ¶100, p. 34.
[55] *Ibid.*, ¶103, p. 35.

consolidation of control area operations and, notwithstanding the details in the proposal, stated that "[i]t is unclear precisely what the functional responsibilities of the Midwest ISO and the control areas will be, and how they will work together to effectuate the new arrangements."[56]

In the subsequent TEMT Order on Rehearing[57], FERC addressed the issue of participation by utilities that were *not* control area operators in reserve sharing pools. Midwest TDUs had argued that utilities that do not operate control areas should be allowed to rely on interruptible load to meet reserve obligations, but the TEMT deferred to control area operators, who determined whether utilities that were *not* control areas could participate in reserve sharing pools. In the Order on Rehearing, the Commission found that "discretionary interruption" of load did not qualify a utility to use such load to meet its reserve obligations. This is an example of the implementation of the NERC functional model, where FERC was intent on assuring that the reliability responsibilities were clearly assigned. The concern on clear assignment of responsibilities would allow market participants to manage such responsibilities in a cost-effective manner; again, consolidation was not required.

The division of control area responsibilities within MISO has continued to evolve. Tension between MISO and pre-existing control area operators led to a settlement agreement in late 2004, which further defined the allocation of control area responsibilities in the form of a contract, not a tariff.[58] This is important because the contract signatories found more confidence, stability or predictability in a contract rather

[56] *Ibid*., ¶124, p. 40 and ¶137, p. 45.
[57] 112 FERC ¶61,086, "Order on Rehearing and Compliance Filing", Docket Nos. ER04-691-038 et al., July 22, 2005.
[58] See filing of October 5, 2004 in FERC Docket No. ER04-691. This distinction is critical because the contractual approach both avoided a jurisdictional battle and provided a more reliable mechanism for implementation than a tariff could have.

than a tariff, which suggests that regulatory decisions are less reliable than voluntary contracts. If so, then regulatory policy may be a less effective way to resolve some issues associated with investments and operations than a contractual approach.

The debate over consolidation of control area functions within MISO also continues in parallel with changes in MISO's division of responsibilities. In 2005, the Organization of MISO States (OMS) investigated the consolidation of control areas within MISO, noting that "MISO staff has reported to the MISO Board that control area consolidation would greatly improve central dispatch and possibly eliminate some of the 'anomalous' dispatch that occurs for 'reliability' purposes. Another opinion is that the move to central dispatch rendered moot the issue and that there are no significant efficiencies to be gained from control area consolidations."[59] Again, this points to the possibility that centralized dispatch with decentralized markets is a substitute for control area consolidation.

By April 2006, MISO had submitted a compliance filing on the status of the transfer of control area functions from individual BAs to MISO. The filing clearly stated that the multiplicity of BAs in MISO, and the specific allocation of responsibilities between MISO and control area operators, did *not* interfere with either reliable operations or with competition in MISO markets.[60] However, MISO did argue that there were potentially more efficient ways to deploy generation resources to meet reliability criteria (e.g., operating reserve requirements), mainly by relying on centralized markets for

[59] See p. 6 of http://misostates.org/AnnualMtg2005OMS_STRATEGIC_PLAN.pdf. See also "Order Rejecting, Without Prejudice, Proposed Tariff Revisions", April 4, 2006, Docket No. ER06-608-000, in which FERC addressed additional issues in dispute between the MISO and utilities that do not operate control areas.

[60] This is not an endorsement of the accuracy of these conclusions, but only an observation that MISO itself has found no significant problems with an allocation of BA responsibilities.

committing and dispatching regulating and operating reserves, and for "co-optimizing" energy and ancillary service supplies.

The approach taken by MISO in the filing of April 2006 raises a fundamental question about market organization and comparative analyses of the provision of control area services.[61] The MISO filing included an analysis of potential costs and benefits associated with further consolidation of BAs, *combined with* the establishment of new markets in certain ancillary services. This analytical approach assumes that consolidation and centralized markets are *necessary complements*. In part this is an artifact of the divestiture of generation resources in the Midwest, which has created new methods for pricing energy and ancillary services such as operating reserves (i.e., reliance on bid-based auctions). In other market or regulatory structures, consolidation and centralized markets would not necessarily be complements. For example, consolidation (or transfer of BA responsibilities) could take place without centralized bid-based markets if the remaining control area(s)/transmission provider(s) had a continuing obligation to provide ancillary services at embedded cost, which is the current *pro forma* requirement under FERC Orders 888 and 890. Market-based transactions in ancillary services on a bilateral basis are possible under the *pro forma* tariff, because transmission customers are permitted to self-supply (including from third-party suppliers) operating reserves and, at least potentially, reactive power. Centralized markets in control area services are thus not the only (or always the best) way to deliver these services. The economic analysis of consolidation of BA functions can and should be separated from the economic analysis of centralized, bid-based unit commitment and dispatch markets. The reality of this separation is evidenced by the bilateral negotiation of arrangements that underlie the

[61] See also the discussion above of GridWest.

creation of new control areas and the switching of entities from one control area to another.

Most recently, MISO asked FERC for permission to transfer certain Balancing Authority (BA) functions from existing BAs to MISO, with the existing BAs continuing to operate as Local Balancing Authorities (LBAs).[62] This is part of the continuing process for the transfer of reliability functions from the BAs to MISO. Testimony provided by MISO in this docket explains the evolutionary nature of this process.[63] Although a new Midwest ISO Balancing Authority Area would be formed and would take over the NERC Balancing Authority responsibilities, LBAs would continue to be responsible for certain "essential local support tasks".[64] In other words, the Midwest ISO would continue to share control area (BA) responsibilities with other entities. Again, complete consolidation and complete decentralization are not the only choices.

Ameren

Within MISO, Ameren decided to consolidate all of its Illinois control areas and terminate the joint dispatch agreement among the same companies (CAOs). In this case, consolidation was seen as a substitute for centralized or joint dispatch of generation, all of which belonged to the same parent company. This demonstrates that consolidation can take place within an ISO by voluntary decisions on the part of entities that operate multiple control areas. In this case, Ameren decided that there were benefits to

[62] See FERC Docket No. ER07-550-000, MISO filing of February 15, 2007.
[63] As of February 2007, there were 24 Balancing Authorities within MISO. Louisville Gas and Electric had withdrawn from the MISO by this point. The specific division of responsibilities between the BAs and MISO is described in detail in the testimony of Roger Harszy, which is part of the February 2007 filing by MISO. FERC's latest order in this docket was issued on June 22, 2007 (ER07-550).
[64] Harszy Testimony at 12 in FERC Docket No. ER07-550-000. See the Midwest ISO Hybrid Model Working Group Report (2000, #209-6). Appendix A: "Implementing Locational Marginal Pricing in a Multi-Control Area Environment", prepared by M. Cadwalader and J. Chandley, LECG, for Commonwealth Edison, and not a product of the Working Group.

consolidation over and above those available from the gradual shift in control area responsibilities to the MISO.[65] However, this result was not mandated by FERC.

Sacramento Municipal Utility District (SMUD), 2002

In June 2002, SMUD began operation of a newly-created control area. This decision to extract the utility from the California ISO was driven by two main factors. First, SMUD expected to be relieved from "unfair rotating outages due to financial issues with participants that comprise the CAISO." These rotating outages were required by the then-current Interconnection Agreement between SMUD and PG&E, despite the fact that SMUD had taken actions during the 2000-01 energy crisis to build a "long" portfolio, which should have avoided the need for outages, and despite differences of opinion at the time about the conditions under which the CAISO could impose load-shedding obligations under its operating agreement with SMUD. Second, SMUD's economic studies showed benefits to consumers of between $2 million and $15 million per year by avoiding CAISO uplift fees, neutrality charges, and other new charges expected to be imposed by the CAISO.[66] These factors were further itemized as: reduced complications relative to conducting business with the CAISO (i.e., reduced transactions costs), avoidance of payment for services not needed but provided by the CAISO, reduced uplift costs from the CAISO, and a reduction in rolling blackouts.[67] At the time, SMUD forecasted an initial investment of $1 million and annual O&M of $1 million to $1.5

[65] See http://www.illinois-auction.com/resources/info/Section_B_-_New_and_Noteworthy_(p4-p8).pdf. In contrast to Ameren, Northwest Independent Power Producers Coalition sees consolidation as a "pre-condition" to economic dispatch. See https://www.ferc.gov/EventCalendar/Files/20051202085746-Kahn,%20NIPPC.PDF.
[66] See Staffing Summary Sheet (SSS) No. SOR01-177, prepared for SMUD Board meeting of November 1, 2001, distributed on October 22, 2001.
[67] See handout for SMUD's Board Integrated Resources & Customer Services Committee, Agenda Item #4, October 31, 2001.

million due to the formation of a separate control area. Offsetting these costs, SMUD forecasted net benefits of up to $17 million per year due to avoidance of charges from the CAISO, and $10-$15 million annually in benefits to consumers due to avoidance of costs passed through the CAISO from PG&E and a reallocation of the CAISO's Grid Management Charge.[68] Although these benefits (avoided costs) are not the same as societal benefits, this kind of calculation demonstrates how FERC policies can skew outcomes in inefficient directions.

Western Area Power Administration, 2004-05

Until the end of 2004, WAPA's Sierra Nevada Region (SNR) was a customer of Pacific Gas & Electric (PG&E) for control area (and other) services. Because the set of contracts providing these services expired at the end of 2004, WAPA/SNR began a process to consider alternative arrangements. Several basic options were screened in a study prepared by Navigant Consulting in June 2003,[69] including (a) operation as a Participating Transmission Owner (PTO) within the California ISO, (b) taking service as a wheeling customer of PG&E and the ISO, (c) operation as a "metered subsystem" within the ISO, and (d) operation as a separate federal control area. Navigant estimated the costs and revenues of each of these alternatives under a variety of assumptions regarding water conditions at the Central Valley Project (CVP), and from four different load perspectives (subsets of SNR's loads) to get a sense of the potential for winners and losers within WAPA's customer base. Viewed only on the cost/revenue basis, the first (PTO) option was forecast to be significantly more expensive: about $25 million more in

[68] It is unclear if these benefits are additive, based on the documentation available.
[69] Navigant Consulting, Inc., "Analysis of Central Valley Project Operational Alternatives", prepared for the Bureau of Reclamation and the Western Area Power Administration, June 12, 2003.

2005 (over $30 million more in 2010) than operating as a separate new control area. The other two alternatives (i.e., wheeling customer and metered subsystem) were also more expensive than the federal control area, so WAPA focused on the last alternative. When other criteria were taken into account, however, becoming a contract-based sub-control area (within SMUD or the ISO) was the final alternative more thoroughly considered and negotiated. These other criteria were judged on a subjective basis: flexibility (retaining institutional options), certainty (future costs), durability (contract versus tariff approach), operating transparency (meeting NERC and WECC operating guidelines), and cost-effectiveness.

Negotiations between WAPA and SMUD, and between WAPA and the ISO, led to SMUD being chosen as the control area within which WAPA would establish a "sub-control area" under contract. The major factor in this final decision was not just initial relative cost, but relative certainty: SMUD was willing to sign a contract with WAPA with stipulated price terms, whereas the ISO would only offer a tariff-based service, which would be subject to future changes depending on regulatory reactions to future tariff filings by the ISO. Following the establishment of the relationship with SMUD, WAPA set up further "nested control areas" within its sub-control area, with entities such as the Modesto Irrigation District, and the Cities of Redding and Roseville. The contract between SMUD and WAPA defines, for example, reserve-sharing responsibilities, and prescribes penalties for WAPA if it fails to meet its allocated share of contingency reserves.[70] A similar approach covers regulating reserves. In turn, the contracts between

[70] Failure to meet contingency reserve obligations triggers penalties that increase with the size of the failure, measured in MW on any given hour. The highest penalties are associated with failures above 25 MW, which carry a penalty equal to three times the ISO's NP-15 Market Clearing Price for the hour(s) of deficiency.

WAPA and entities such as the City of Redding, which operate electrical systems within the WAPA sub-control area, allocate WAPA's reserve obligations based on load-ratio shares.[71] The web of contracts also essentially provides for default provision of reserves by the "next highest" entity in the web: SMUD provides default service for WAPA, and WAPA provides default service for MID, Shasta Lake, Redding and Roseville. In this manner, each entity knows what its obligations are, but also has agreed to a set of default procedures and payments (posted charges, penalties, and settlement of deviation accounts) for failure to meet its obligations.

This multilayered system of control areas may be unique, but it demonstrates the viability of a contractually-based approach to allocating control area responsibilities. Given that NERC, now the FERC-approved Electric Reliability Organization (ERO), has disaggregated and identified individual BA functions, it is at least theoretically possible for market participants to decide on a bilateral or multilateral basis which entity is best situated to perform each function. In the past, the standard (but not exclusive) pattern has been for one entity, designated as a "control area", to perform all of the functions. With disaggregation of these functions, it is at least possible for entities to consider performing some, all or none of the functions, which has led to new arrangements such as the three-layer approach of SMUD-WAPA-Redding. In effect, the aggregate set of control responsibilities is being performed by a collection of entities, which then operate as a single control area from the perspective of entities <u>outside</u> that control area.

[71] That is, Shasta Lake, Redding, Roseville, and WAPA each agree to carry a share of the WAPA total reserve obligation based on the previous year's annual peak load (MW).

Pend Oreille County PUD, 1999

In late 1999, Pend Oreille County PUD switched from BPA's control area to Avista's. The motivations for this change were related mainly to one large load of Pend Oreille, which had the ability to change by 40 MW on very short notice. Pend Oreille was (and is) a "partial requirements" customer of BPA: part of the PUD's load is met with its own resources and the remainder with wholesale power purchased from BPA. Under contracts signed in the early 1980s with BPA, Pend Oreille was permitted to alter its purchases of federal power to reflect changes in load, but over time BPA became more strict about such changes. Eventually BPA required the PUD to set up a "deviation account" to track differences between scheduled and actual purchases from BPA (plus or minus). Additions to and withdrawals from the deviation account had to be managed within limits. In addition, in 1996 BPA unbundled its power and transmission rates; established a new charge for load regulation service, applied only to customers inside BPA's control area; and increased the charges for the use of the deviation account. These changes created new incentives for Pend Oreille to seek alternative suppliers for control area services. Avista offered reductions in the cost of following Pend Oreille's actual loads, a deviation account with less complexity and more flexibility, as well as other services for the PUD's own generation at the Box Canyon project.

Okanogan Public Utility District, 1999

In January 1999, Okanogan Public Utility District (PUD), in north central Washington State, moved from the BPA control area to that of Douglas County PUD. There were several reasons for this decision, including generation ownership rights, prices charged by BPA for certain generation support services, changes in transmission ownership, and transactions costs, broadly defined. Okanogan had previously joined with Douglas in the decision to build the Wells generation project, located in Douglas County. As a result, Okanogan had certain capacity and energy rights from Wells to help meet its retail load obligations. The standard practice of many smaller utilities in the Northwest with generation ownership rights was to sign "Service and Exchange Agreements" with BPA, under which BPA would continue to meet the entire metered load of the utilities, but would credit the utilities' bills with the output of the utilities' resources, which were integrated into BPA's generation system. BPA charged for this service.

Over time, Okanogan took incremental steps toward greater involvement in managing its resources. In the early 1990s, Okanogan purchased transmission assets from BPA, thus eliminating charges by BPA for wheeling Okanogan's share of the Wells generation project, also located in Douglas County. In the mid-1990s, BPA changed the terms of the Service and Exchange Agreement, reducing the value of the Wells share to Okanogan. In addition, BPA unbundled its transmission and ancillary services in 1996, in an effort to achieve "safe harbor" status under FERC Order 888. Unbundling meant that some ancillary services could be self-supplied or purchased from third parties. It became economical for Okanogan to self-supply ancillary services from its Wells share, but only if Okanogan moved out of BPA's control area. The ancillary services could have been sold into the market (e.g., as operating reserves), but at the time the market for such services was not well developed. In addition, at the time it was also possible to avoid at least some of BPA's posted charges for peak-period power, as well as BPA's charges for ancillary services, and this offered more certain economic value to Okanogan.

In general, transactions costs incurred as an entity within Douglas' control area are lower than those associated with BPA's control area. More recently, operating from within Douglas' control area has permitted Okanogan to integrate a new wind resource using its share of the flexibility in the Wells project. Again, self-supply of these services has proved more economical and less risky than relying on a thin market.

Clark County PUD

Clark County PUD, in southwestern Washington State, has changed control areas twice since the mid-1990s, first moving out of BPA's control area and then moving back in. The factual context for these changes explains the economic value of both decisions to the PUD. In the mid-1990s, Clark decided to significantly reduce its reliance on BPA for wholesale power supplies. As a result, the PUD built the River Road combined cycle combustion turbine (CCCT), which in 2007 constituted about 40 percent of the utility's power supplies. In addition, Clark made shorter-term commitments to purchase power from other wholesale suppliers, who were offering relative low prices at the time. Discussions with other suppliers of control area services led to an arrangement with PacifiCorp, based in part on the location of PacifiCorp transmission lines that ran through the PUD's service territory and close to the River Road plant. PacifiCorp also provided services to assist Clark in the operation and integration of the CCCT as part of the package, such as a storage account for tracking the actual output of the River Road plant.

When the original contract with PacifiCorp was nearing its termination date, Clark reconsidered its options. The shutdown of an aluminum smelter in Clark County created surplus capacity at a BPA substation in the county, and it was relatively easy to change the CT's interconnection from PacifiCorp to BPA. Also, the River Road plant's location is such that it affects the operation of BPA's control area, which surrounds Clark, thus providing an incentive on BPA's part to cooperate with Clark. BPA permitted Clark to change power products, thus shifting the responsibility for following actual load back onto BPA. Clark will also be able to avoid penalties for errors in scheduling of its purchases of power from BPA, which had been experienced under the arrangement with PacifiCorp.

Eugene Water and Electric Board

The Eugene Water and Electric Board (EWEB) demonstrates yet another example of how control area responsibilities shift over time in response to constraints and relative prices. In the 1980s (and even before), EWEB controlled its interchange with other control areas, managed ACE, controlled frequency with its own generation units, and made time-error corrections. EWEB was not "certified" as a control area at the time, but acted "as if" it were a control area, in the sense that it complied with reliability criteria. When certification became more stringent (and thus more expensive) in the 1990s, EWEB elected to become a "nested" control area within BPA's control area. This was followed by an 18-month experiment triggered by the shift in reserve obligations from (a) being defined by generation to (b) being defined by loads. During the experiment, EWEB was deemed to be a percentage of federal (BPA) generation, and its generation units were set up to share any reserve response placed on BPA. At the time, it was more economical for EWEB to contribute to this reserve-sharing pool than to pay for reserves based on its loads. EWEB eventually moved fully into BPA's control area, purchasing

Regulation and Frequency Response service from BPA's transmission business line as a FERC-required ancillary service. However, EWEB uses the third-party supply option under BPA's OATT and purchases operating reserves (spinning and non-spinning) from another Northwest utility. All of these decisions were driven by the economic options available to meet obligations under tariffs and reliability criteria. As the obligations (i.e., the constraints) changed, and the relative costs of options to meet these obligations (i.e., the economics) changed, EWEB's decisions changed accordingly.

TransAlta

In 1999, TransAlta purchased the Centralia coal-fired generation plant in western Washington. Previously, Centralia had eight utility owners, including PacifiCorp; the plant was in PacifiCorp's control; and PacifiCorp acted as plant operator, aggregating schedules from the eight owners, figuring out optimal operations, dispatching the plant according to the owners' schedules, but ultimately acting as the balancing authority. The eight owners worked through PacifiCorp to exercise their rights.

In May 2000, the sale of the plant closed and TransAlta switched the plant to BPA's control area. There were several motivating factors for this change. First, the generating plant was sold, but the "grandfathered" transmission contracts were retained by the utilities who sold their share of Centralia to TransAlta. Centralia remained a Point of Receipt (POR) for the contract holders with the various utilities being the Points of Delivery (PODs). Without the grandfathered transmission contracts, TransAlta had to acquire new transmission service from BPA.[72] This would mean that for the new owner,

[72] This might be described as a type of "contractual stranding" of the asset: ownership of the generation did not, and does not, guarantee transmission rights to move the output of the plant to markets. Previously,

TransAlta, leaving the plant in PacifiCorp's control area would have meant ("pancaked") payments both to PacifiCorp and BPA for access to loads and markets. Moving to the BPA control area thus reduced transmission costs. Second, TransAlta took over the operation and dispatch of the plant, thus raising issues of the effects of plant operations on PacifiCorp's control area operations as a whole. PacifiCorp's west side control area is relatively small when compared to their east side control area. Moving to the BPA control area made sense because of the size of the plant (1,400 MW nameplate): BPA's larger control area could better integrate the operations of this particular generator.

Summary

This review of changes in control area affiliation amply illustrates the many different factors supporting such changes. The bottom line or major motivation is the ability to control costs and risks, which should not be surprising. Constraints on choices are also critical: the availability of transmission capacity, the costs of alternatives, the expiration of contracts previously governing control area services, the particular types of loads and resources at a given utility, and the choice between regulated tariffs and bilateral or multilateral contracting. It is also important to recognize that changes have occurred and are continuing to occur regarding the distribution of responsibility for supplying control area services. The "real world" of control area operations is one characterized by considerable experimentation and negotiation, completely aside from regulatory policies, but within the limitations imposed by the obligation to meet reliability criteria. There is clearly no "one size fits all" solution to this problem.

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the plant had been dynamically scheduled by PacifiCorp and others across BPA's transmission capacity in addition to holding the transmission path rights. Others just had the physical paths and did not employ dynamic scheduling provisions.

Control Area Performance during Blackouts

One critical question in any analysis of control area consolidation is the potential for changes in the overall reliability of the grid. Although economic analyses, as noted above, have attempted to estimate the potential costs and benefits of consolidation, it is possible that changes in control area responsibilities would also alter the likelihood, frequency, or magnitude of widespread outages. In this section, reports on wide-spread blackouts are examined to see if any plausible connections can be made between the number of control areas and the potential for blackouts.

2003 Eastern Interconnection

The widespread blackout in the Eastern Interconnection in August 2003 has led to several investigations, reports, and recommendations for change. Interestingly enough, none of these reports points to any evidence that the multiplicity of control areas was a cause for the initiation of the black-out, or a factor in its duration or geographical extent, or in restoration of service, which took several days before being completed. Rather, the focus has been on the failure of the existing control areas and regulatory authorities to understand, comply, communicate and oversee. That is, transmission system operators do not clearly understand the implications of certain operating conditions on the grid, they do not always comply with reliability standards, and they do not always communicate well during emergencies. In addition, regulatory authorities have failed to fulfill their responsibilities to ensure compliance with reliability criteria.

The Final Report (FR) by U.S. and Canadian government agencies on the blackout in U.S. did not recommend anything regarding consolidation or division of control area responsibilities.[73] Recommendation #20 did, however, state as follows (p. 3): "[e]stablish clear definitions for *normal, alert* and *emergency* operational system conditions. Clarify roles, responsibilities, and authorities of reliability coordinators and control areas under each condition." More specifically,

- Some control areas failed to perform studies that would have alerted them to potential problems. (p. 18, Group 1., Item B.) FirstEnergy was unaware of conditions on its own system. (p. 66.)
- NERC was faulted for not auditing control areas. (p. 19.) NERC Policy 5 was faulted for not adequately addressing operations during conditions that are not fully understood. (p. 21.)
- MISO's Violation #4 was the failure to notify other control areas of problems. (p. 22.) FirstEnergy committed the same error. (p. 56.) Dayton Power & Light also failed to notify others of problems on its own system. (p. 71, note 8.)
- "The Task Force believes that the Interim Report accurately identified the primary causes of the blackout. It also believes that had existing reliability requirements been followed, either the disturbance in northern Ohio that evolved on August 14 into a blackout would not have occurred, or it would have been contained within the FE control area." (p. 148.)
- "During the data collection phase of the blackout investigation, when control areas were asked for information pertaining to merchant generation within their area, the requested data was frequently not available because the control area had not recorded the status or output of the generator at a given point in time. Some control area operators also asserted that some of the data that did exist was commercially sensitive or confidential." (pp. 160-1.)

The Final Report did point to the possible need to eliminate "inappropriate commercial incentives to retain control area status that do not support reliability objectives" (p. 145). However, the Final Report noted that this could be accomplished *not* by interfering with voluntary bilateral exchange, but by enforcement of reliability criteria, and this is exactly what the Task Force recommended (p. 145). The Task Force also noted the following:

[73] See U.S.-Canada Power System Outage Task Force, "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations", April 2004. The report on the blackout by the Michigan Public Service Commission (available at www.ksg.harvard.edu/hepg/Blackout.htm) also does not say anything about the number or size of control areas.

> Some observers believe that some U.S. regions have too many control areas performing one or more of the four critical reliability functions. In many cases, these entities exist to retain commercial advantages associated with some of these functions. The resulting institutional fragmentation and decentralization of control leads to a higher number of operating contacts and seams, complex coordination requirements, misalignment of control areas with other electrical boundaries and/or operating hierarchies, inconsistent practices and tools, and increased compliance monitoring requirements. These consequences hamper the efficiency and reliability of grid operations. . . . Moreover, it is not clear that small control areas are financially able to provide the facilities and services needed to perform control area functions at the level needed to maintain reliability. (p. 146.)

However, no actual evidence was presented in support of these arguments, so it is really not possible to conclude that the number of control areas is "too high" in this area of the U.S. and Canada.

In August 2003, compliance with reliability criteria was *the* problem: lack of compliance was a sufficient condition for the blackout. Another causative factor may have been industry restructuring itself: some have argued that "[d]eregulation has resulted in a much more intensive use of the transmission system: more power is being transmitted over longer distances during a larger proportion of the time. Since the system is operated at its limits for longer periods of time, the probability of a blackout therefore increases."[74] This implies that industry restructuring in and of itself may have been responsible for the lack of communication and information exchange, which in turn led to the particularly widespread character of the blackout.[75]

The Final Blackout Report by NERC (July 13, 2004) also suggests that the ability to "island" the electrical system in the Northeast contributed to both *limiting the extent* of

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[74] See Daniel Kirschen and Goran Strbac, "Why investments do not prevent blackouts", UMIST, Manchester, UK, 27 August 2003, unnumbered p. 8; available at www.ksg.harvard.edu/hepg/Blackout.htm. See also "Contributions of the Restructuring of the Electric Power Industry to the August 14, 2003 Blackout", August 2005, by Power Engineers Supporting Truth (www.pest-03.org)

[75] Similarly, the Interim Report of the New York ISO (January 8, 2004) pointed to the need for better communication generally among RTOs, ISOs, and control areas (p. 43).

the outage and *restoring* service after the outage had occurred. First, underfrequency load-shedding schemes in New England, combined with some fast-start generation, were able to stabilize that region plus the Canadian Maritime once New England had separated from the rest of the Eastern Interconnection (p. 87). These load-shedding schemes were arguably designed to manage problems of a limited magnitude (in terms of affected load), and thus were able to stabilize the system once it had shrunk, effectively, due to the natural islanding that occurred. Second, even though most of the Northeast blacked out by 16:13 EDT, some areas "in which a close generation-demand balance could be maintained remained operational." For example, one relatively large island remained in operation in western New York, supported by large hydro generators in Ontario and upstate New York, as well as a 765-kV interconnection with Québec (pp. 91-92). "This island formed the basis for restoration in both New York and Ontario." (p. 92) Finally, the list of major causes of the blackout (p. 94) said nothing about the number or size of control areas, but pointed to a lack of communication, a lack of compliance with reliability standards, a lack of ensuring that reliability standards were met, inaccurate data, inconsistent application of system protection technologies, poor vegetation management, poor operator training, and a lack of tools to "see" system conditions (p. 94).

European Blackouts

Two significant blackouts occurred in 2003 and 2006 in Italy and Germany, respectively, leading to investigations of the causes and proposed corrective actions that were similar to those following the 2003 blackout in the Northeastern U.S. The Union for the Co-ordination of Transmission of Electricity (UCTE) has investigated and issued reports on these blackouts (see www.ucte.org).

UCTE's final report on the 2003 blackout did not mention anything about reconfiguring control areas; rather, it focused on better coordination, information exchange, and enforcement of reliability standards.[76] These changes were recommended in light of the fact that the European transmission network was being called upon to support a much higher level of cross-border power exchanges than were originally considered when the network was designed, largely within each country separately. These larger exchanges are due, in turn, to a series of actions that allowed utilities in one country to rely on utilities in other countries, especially for reserves.[77] The development of security (reliability) protocols lagged behind the development of such power exchanges, much as in the U.S., where a new emphasis on national mandatory reliability standards was enacted in 2005.

The press release from UCTE (January 30, 2007) on the 2006 blackout included the following conclusions: "[d]ue to the adequate performance of the automatic counter-measures in each individual TSO control area and additional manual actions by TSOs [transmission system operators] a few minutes after the splitting, a further deterioration of the system conditions and a Europe wide black-out could be avoided. Full resynchronization of the UCTE system was completed 38 minutes after the splitting and the TSOs were able to re-establish a normal situation in all European countries in less than 2 hours. The *decentralized* responsibilities of TSOs and their *individual* defence

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[76] A *Deutsche Welle* report on January 30, 2007 pointed to the lack of communication after the initial outage by EO.N, Germany's largest energy company: "Andere europäische Netzbetreiber seien über die Panne und ihre gravierenden Auswirkungen nicht informiert worden. Dadurch habe es einen 'Dominoeffekt' gegeben, der zum Zusammenbruch der Netze in vielen EU-Staaten führte, sagte Piebalgs [Commissioner of the European Union for Energy]".
[77] UCTE Report, April 2004.

plans have demonstrated their efficiency." (Emphasis added.) This supports the reliability benefits of greater decentralization of control over operations, combined with better communication networks.

Alternative Approaches to Achieving the Objectives of CCA

First, there is often a tendency in this debate to erroneously conflate different issues and solutions to different problems. CCA is presented by some as a single solution to a number of problems, rather than as one of several different solutions to separate problems. This makes it more difficult to evaluate options for incremental changes, which is the appropriate economic approach. Also, if CCA is conflated with establishment of centralized markets, and if the two are implemented at the same time, the disadvantages and advantages of centralized markets can easily be confused with the disadvantages and advantages of CCA. A better approach would be to identify specific problems (e.g., discriminatory access to control area services, or greater-than-optimal number of generating units on regulation) and determine the options for solving such problems. It may be that CCA *could* be implemented in conjunction with establishment of centralized markets in some instances, but as we have seen there is no *necessary* connection between the two: studies have shown the ability, for example, to share regulating reserves without consolidating control areas and without establishing a market in regulating reserves.

Second, it is clear from the national experience that a "one size fits all" approach is not reasonable. In some cases, the problems of discrimination and inefficient provision of regulating reserves *may* justify the consolidation of control areas (e.g., upper Midwest), but in other cases there is evidence that consolidation is *not* the right answer (e.g., SPP and California). The experience with control area switching shows that the economic motivations for (and reliability consequences of) are definitely case-specific. Sometimes a utility has a particular load or generator that would benefit from being integrated into a different control area's operations, and switching allows those benefits to be captured. Multiplicity of control areas offers greater choice for those considering control area switching. The result is a set of bilateral markets in control area services, in effect.

One issue that is normally overlooked in the debate on control area consolidation is the physical ability of the transmission grid to support the increase in transactions that are postulated to lead to economic benefits. The existing grid has been built based on a certain institutional design, including the assignment of responsibilities for certain reliability functions. The capacity of the interconnections between control areas is limited physically as a result of these investment decisions. Unless sufficient surplus transmission capacity exists on the tie-lines between control areas, collapsing control responsibilities will not necessarily bring benefits in terms of either reliability or cost. A recent investigation of control area "integration" in Europe points this out:

> [t]he interconnection capacities between Control Areas have, generally speaking, not been designed for commercial exchanges exceeding the quantities that are presently managed. Integration of Control Areas would not increase by itself the capacities available for commodity trade. On the contrary, integration of balancing markets would imply that more interconnection capacity must be reserved for balancing and ancillary services. In this respect, a trade-off must be made.[78]

The studies reviewed above of the potential benefits of control area consolidation have not explicitly taken into account this trade-off: greater trade in ancillary services on

[78] F. Vandenberghe, "Development of Interconnections and Reliability Standards", Chapter 5 in *Electricity Trade in Europe: Review of the Economic and Regulatory Changes*, J. Bielecki and M.G. Desta, eds., Kluwer Law International, The Hague, 2004, p. 109.

existing transmission lines may mean a reduction in trade in energy itself, unless additional transmission capacity is built. The potential benefits of control area consolidation must take into account the opportunity cost of the transmission capacity that would be reserved for increased trade in ancillary services, or the net benefits will be overstated.

Another way of approaching this issue is to ask, could the benefits of CCA be accomplished without consolidation? As we have seen in the case of SMUD and WAPA in California, a contract-based approach to "layered" or "nested" control area operations is able to allocate responsibilities of control across several entities.[79] In addition, other approaches have been suggested but not actually implemented:

- In 2000, Richard Tabors proposed a "real flow" approach to congestion management within the structure of an RTO, which would not require consolidation of control areas.[80]
- The American Wind Energy Association has promoted "virtual control area consolidation" in lieu of physical consolidation.[81]
- The Northwest Wind Integration Action Plan (WIAP) points to expanded markets in control area services and reserve sharing programs as alternatives to consolidation.[82]
- ColumbiaGrid is investigating an ACE diversity interchange.[83]

[79] See L.R. Day, "Control Area Trends: Principles and Responses", *IEEE Computer Applications in Power*, vol. 8, issue 2, April 1995, pp. 34-39.
[80] http://www.ksg.harvard.edu/hepg/flowgate/Real%20Flow-faq%207-20-00.pdf
[81] See comments in RM05-25-000, Nov. 22, 2005: http://www.awea.org/policy/regulatory_policy/transmission_documents/Access/AWEA_comments_on_OATT.pdf
[82] http://www.nwcouncil.org/energy/Wind/library/2007-1.htm
[83] http://www.columbiagrid.org/?page_id=557

- SPP determined that sharing ACE diversity among control areas could accomplish the goal of reducing regulating reserves.
- GridFlorida proposed a single "RTO control area" with embedded "control zones" defined by pre-existing utility control areas.

Therefore, it is reasonable to conclude that there are several different ways to achieve potential benefits of consolidation of control areas: e.g., allocation of control responsibilities between umbrella and nested entities, reserve sharing agreements, pooling agreements, and stricter enforcement of access to ancillary services on a non-discriminatory basis. It is also reasonable to conclude that negotiated agreements, in many cases subject to regulatory approval, can achieve these benefits without consolidation.

Cost/Benefit Analysis of Multiple Control Areas

As the examples discussed above demonstrate, some basic cost-benefit analysis is normally associated with decisions to create control areas or to switch from one control area to another. These cost-benefit analyses are usually undertaken from the perspective of the entity making the decision, which could be a utility, an IPP, or an individual end-use customer. From a broader perspective, any organized attempt to promote either consolidation or "proliferation" should be based on reasonable estimates of the costs and benefits from a societal perspective, and on the assumption that entities (existing or new) will comply with reliability standards. That is, given such compliance obligations, the question should be "what is the least expensive distribution of control area (or balancing authority) responsibilities?"[84]

The costs of control area operation, and thus (to some extent) the avoided costs if control areas were to consolidate, are relatively easy to quantify.

> The relevant costs of operating a control area were those related to the obligation to provide generation capacity and energy to support network operation, including the costs of:
> - reserves (planning and operation)
> - energy from operating reserves during system emergencies, especially at times of low system frequency regardless of market price (this energy was returned in kind, usually during cheaper, low-load periods)
> - control area losses
> - generation redispatch to prevent transmission overloads regardless of cause (service to own load or actions of neighboring utility)
>
> Control area costs also included those related to each utility's obligation to build its share of transmission assets to maintain an adequate network for all participants. In most parts of the country, the costs of operating a control area were proportional to the size of the utility, and state regulators considered these to be prudent and passed them on to the customers.[85]

Entities considering the formation of new control areas, such as Turlock and SMUD, as well as those switching between control areas, have undertaken analyses of the expected incremental costs of operation, including hardware, software, staffing, training, and changes in operations to meet reserve requirements. Incremental and decremental costs may not be symmetrical: once established, the ability to avoid costs by consolidation may be less than the incremental costs associated with setting up the control area in the first place. However, these will be fact-specific kinds of analyses.

[84] ELCON urges cost-benefit test for consolidation. http://elcon.org/Documents/120103ELCONComments.pdf. Also, the Clean and Diversified Energy Initiative Transmission Task Force of the Western Governors' Association advocates case-by-case analysis of the costs and benefits of consolidation. http://www.awea.org/policy/regulatory_policy/transmission_documents/WGA_TransmissionReport_3-2-06.pdf

[85] José Delgado, "The Blackout of 2003 and its Connection to Open Access", August 2005, available at www.ksg.harvard.edu/hepg/Blackout.htm, p. 2, note 4.

Aside from the incremental costs that would be borne by the control area customers, there is the possibility of external costs imposed on other customers through market effects, if new control areas are formed. Such external costs could derive from two sources: changes in market operations generally, and “stranded costs” that are specific to individual utilities or market participants. The former would presumably be based on barriers to trade established or amplified by the existence of the new control area. This argument has been used in dockets regarding both MISO and SPP, where some TDUs have pointed to the potential for discrimination by providers of control area services. Such discrimination could potentially interfere with competition and thus yield inefficiencies. However, the list of potential remedies to competitive problems should include not only consolidation of control areas, but also prohibitions on discriminatory practices on the part of suppliers of control area services and reserve sharing agreements. In Order 890, FERC is moving to eliminate continuing sources of potential discrimination in transmission access, and could be encouraged (via complaint) to look at problems in specific bilateral or multilateral markets in control area services. As we have seen above, reserve sharing agreements, including ACE diversity interchange and ACE sharing, are being contemplated in both the Northwest and in the SPP. Again, these changes can be put into place without consolidation of control areas.

The potential benefits of a multiplicity of control areas may be harder to quantify, but can certainly be described. Based on the evidence, the ability to establish new control areas and to switch between control areas has clearly allowed some customers to obtain more reliable and/or more economical service. Switching itself is proof of the existence of bilateral markets in control area services, without the costs and risks associated with centralized market design.

Is there an "optimal size" or a "range of optimal sizes" for a control area? If so, what are the determinants? Some observers argue that control areas can both be "too large" and "too small". Control areas that are *too large* could compromise reliability, because they would be relying on distant resources to provide reserve services and because the complexity of operations increases with the geographical scale of the control area.

> There is likely to be a tradeoff between the location of reserves and the strength of the transmission system. If the system's transmission capability is very limited (or fully utilized), reserves for possible contingencies must be provided "locally" so that transmission is not necessary to access the reserves. If the transmission system has ample capacity available, the use of remote reserves is practical.[86]

Control areas can also be *too small* because of the increase in transactions costs associated with doing business across multiple control areas.[87] However, the border between "too small" and "too large" is not clearly defined.

> Greater consolidation of system operation functions across integrated transmission systems has the potential to reduce transaction costs, increase consistency of application of reliability rules and improve real-time coordination and action to manage transmission system security. However, these benefits may accrue at the expense of more flexible, local responses to manage system security. More localised control areas may provide greater flexibility to accommodate local differences in market rules, structures, generation and fuel mix and public policy.[88]

Thus, the facts on the ground will determine the optimal number and size of control areas. In addition, changes in technology and the costs of telecommunication and system

[86] Fernando Alvarado and Shmuel Oren, "Transmission System Operation and Interconnection", in National Transmission Grid Study Issue Papers, 2002, p. A-7. See also B. Kirby and E. Hirst, "Reliability Management and Oversight", Appendix B to the National Transmission Grid Study, esp. p. B-4.
[87] Kirby and Hirst, *ibid*.
[88] International Energy Agency, "Learning From the Blackouts: Transmission System Security in Competitive Electricity Markets", 2005, p. 125.

operations (both generation and transmission) could easily change the optimal number and size of control areas in any given part of the country over time. There is no reason to believe that the "optimum" is static, or that the optimum can be defined in the same way for all regions of the country.

Conclusions and Recommendations

A review of actual experiences of market participants and regulatory decisions reveals several facts. First, outside of centralized RTO/ISO markets, new control areas and sub-control areas have formed in the last few years, and some utilities and IPPs have changed control areas, in one case more than once. All of these changes have taken place while remaining in compliance with reliability standards established by NERC and WECC.

Second, there are circumstances in which consolidation appears a rational reaction to patterns of discrimination, but other remedies may be possible.

Third, changes in transmission rate design may promote bilateral markets in control area services, without the need to consolidate control areas.

Fourth, bilateral trades (thus markets) in control area services exist without consolidation of control areas.

Fifth, there is no simple answer to the question: how large should a control area be? Control areas can be both "too large" and "too small".

Sixth, reserve sharing agreements, including ACE diversity interchange, may be a substitute for consolidation of control areas.

Seventh, studies of the costs and benefits of control area consolidation have, in some cases, conflated changes in control area operations with changes in market design and in transmission access and pricing. Except for individual entities making decisions about their own operations, regional or sub-regional studies of the benefits and costs of consolidation do not yield convincing conclusions.

Eighth, in at least two cases, FERC has approved agreements to establish pseudo-ties, which are *another* substitute for consolidation of control areas.

Ninth, in at least one ISO (i.e., the Midwest ISO), an evolutionary approach is being taken to the reallocation of control area responsibilities that has lasted almost a decade and promises further incremental changes.

Tenth, there is no evidence that the multiplicity of control areas contributed in any way to the extent of blackouts in the northeastern U.S. in 2003, or in Europe in 2003 and 2006. To the contrary, observers have noted that the distribution of responsibility for control of the grid may have helped limit the extent of the outage and contributed to recovery.

For the future, FERC should recognize that the existence of multiple control areas permits greater choice for consumers (acting through their utilities), and can promote the development of bilateral markets against which the performance of centralized markets can be compared. Thus, the Commission should remain open to the formation of new control areas and to agreements that result in the switch of loads and resources between control areas, as long as reliability criteria remain a binding constraint on all entities involved in the generation, transmission, and distribution of electricity.